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FOAM FRACTURING EVALUATION

by

A. Richard Sinclair
Fracturing Technology, Inc.

for

EGSP
OPEN FILE #112

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TR78-21
July 1978

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I. SUMMARY & CONCLUSIONS

Overall, Foam Fracs appear to be quite suitable for the Devonian Shale since the formation is shallow, low temperature and low permeability. The Devonian also needs to have quick clean up to prevent formation damage and this is an area where foam fluids are excellent.

The report discusses the available data on foam fracs and evaluates the state of the art of the foam fluid as it applies to hydraulic fracturing stimulation of the Devonian Shale.

Different ways to conduct foam treatments are discussed. Limits of foams are presented with a section on how to extend these limits. The analysis of the treatment after stimulation is discussed with recommendations for further testing.

Computer programs have been run to illustrate the effect of fluid leakoff on fracture geometry with a constant viscosity foam; however, more exact analysis is needed since the effective foam viscosity depends on pressure changes, flow rates, fracture widths, and formation permeability during the dynamic fracturing operation.

The conclusions of the study on foam fracturing fluids are as follows:

1. Foam fluids are effective in certain applications:
   - A. In areas where quick clean up is essential
   - B. In formations of low permeability
   - C. At shallow depths
   - D. At low temperatures.

2. When used in the Devonian Shales which can be naturally fractured, 100 mesh sand should be used as the lead in sand for help in fluid loss control.

3. Complete evaluation and quantitative comparisons to other techniques will require that a pressure build up analysis be run on the foam fracs and on other treatments where comparisons are needed.

4. A modified Foam Frac or modified equipment should be considered if productivity is curtailed by low proppant concentrations which are characteristic of the foam treatments.

5. A new computer program is needed to help design foam fracs. It would be useful for future treatments to assess the effects of updated information and properties of foams on the required results.

These conclusions are discussed in detail in the body of the report.

II. INTRODUCTION

A recent innovation in the developing technology of hydraulic fracturing is the use of foam as a new fracturing fluid[1,2]. Foam seems to fit the definition of a desirable frac fluid since it can hydraulically create a fracture, it can carry sand into the fracture, it minimizes formation permeability damage, and it cleans up quickly after the job.

Foam has been used quite widely in the oil and gas industry for the last 5 years. During 1975[3], over 200 Foam Fracs were designed for many geographical areas. Table 1 shows the states and counties where Foam Fracs were used. The results of some of these treatments are given in Table 2 which shows the type of formation, depths, injection rate, treating pressure, amount of proppant, and early results of these 1975 treatments.

In the E.G.S.P. program[21] at least 6 foam fracs have been reported as of May 15, 1978. These treatments are shown in Table 3. Most of these treatments used a 75 quality foam at an injection rate of 25 to 40 BPM. Although results appear to be acceptable, the results are difficult to compare directly with other treatments since these have been used over a wide area and with unknown downhole conditions such as effective formation permeability, amount of natural fracturing and various mechanical difficulties.

TABLE 1. GEOGRAPHIC LOCATIONS WHERE SOME STABLE FOAM FRACTURING JOBS WERE PERFORMED IN 1975.

State	Counties
Texas	Val Verde, Sterling, Ward, Sutton, Edwards, Webb, Crockett, Reeves, Hale, Hemphill, Coke, Irion, Upton
Colorado	Wellol, Cheyenne, Weld, Elbert, Rio Blanco, Larmier
Oklahoma	Texas, Okmulgee, Carter, Kay, Pittsburg
Kansas	Morton, Sherman, Grant
Wyoming	Converse, Niobrara, Sweetwater
New Mexico	San Juan, Lea
California	Fresno
Pennsylvania	Forrest

TABLE 2. SAMPLE OF FIELD RESULTS

Formation	Depth (ft)	Mode*	Fluid Rate (BPM)	Foam Rate (BPM)	Wellhead Treating Pressure (psi)	Proppant Amount (lbs)	Proppant Type (Mesh)	Production Before	Production After
Olmos	7,403	1	4.2	16	4,600	38,000	10-20	500 MCFD	1400 MCFD
Council Grove	2,900	3	16	58	1,600	100,000	20-40	100 MCFD	2400 MCFD
Mancus-B	2,300	2	8	38	2,640	82,000	20-40	100 MCFD	800 MCFD
Picture Cliff	3,150	2	4	15	1,800	15,000 5,000	10-20 8-12	**	215 MCFD
Picture Cliff	1,860	2	3.5	10	1,500	3,000 1,500	10-20 8-12	**	1096 MCFD
Strawn	6,500	3	4	12	4,200	37,500	20-40	**	44 BOPD
Canyon	7,000	2	4.5	18	5,200	61,000	20-40	16 MCFD	300 MCFD
Canyon	6,895	2	4.5	18	4,695	25,000	20-40	75 MCFD	250 MCFD
Douglas	7,040	2	7	24	3,000	53,000	10-20	**	10,000 MCFD
Clearfork	5,000	3	7.5	30	2,200	75,670	20-40	9 BOPD	23 BOPD

* Mode
1. Tubing
2. Casing
3. Manifolded Tubing & Casing

** New Completion - Test Data Prior to Frac Not Available

FOAM FRACTURING
(CONVENTIONAL SIZE)

Formation Type	Vol (gal)	Sand (Lbs)	Rate (BPM)	Depth (Ft)	Perf Ht Ft	Production Before/After	Cost ($$10^3$)	State/County	Contractor	Well No
Br Gr Sh	40,000(4)	40,000(4)	30	2328-2675	350(4)	3/80	35.5	Ky/Perry	Ky-WV	7239
Upper/Middle Br Sh	50,000	55,000	25	3174-40 3412-35	88	0/350	18.4	"	"	7248
New Albany Sh	45,000	54,000	25	2148-2320	134	0/15	17.0	Ky/Christian	Orbit	Ray Clark #1
Upper/Middle Br Sh	50,000	55,000	25	2560-2590, 2730-2750	30	0/103	15.7	Ky/Perry	Ky/WV	1527
Antrim	45,000	50,000	25	1308-1540	72	0/130	17.8	Mi/Otsego	Welch	Otsego 1-15
Upper/Middle Br Sh	50,000	64,000	40	2735-2777 2929-3041	154	0/350	17.5	WV/Mason	Reel Energy	DSK #3

TABLE 3 SUMMARY OF E.G.S.P. CONVENTIONAL FOAM TREATMENTS AS OF 5/15/78

III. APPROACH TO FOAM FRAC EVALUATION

To study foam fracs, particularly in the Devonian Shales, the records of all of the foam treatments were examined to see if the jobs went as planned and to verify predicted rates, pressures and sand schedules. After this early examination of the treating reports, a thorough survey of the literature was undertaken to familiarize myself with the present day state of technology of foam fracturing. Many calls were made to service companies, laboratories, oil companies, and engineers and authors of foam papers who were familiar with the state of the art.

From these conversations and articles the strengths, weaknesses, and uses of foam fracs begin to emerge. Personal opinions of organizations and people selling foam materials were discounted and an objective look at the subject was attempted.

To illustrate the effects of the fluid properties of foam in fracturing it was decided to run 2 types of fracturing programs. A simple one to run parameter studies and trends, and a more exact one to account for other variables in the fracture generation process. The first parametric studies were run with a Kerns and Perkins[11,16] type calculation. A more exact program based on Barenblatts Equations[20] and Kristianovich and Zheltov's[19] approach was also taken to examine the effects of fluid leakoff of foams.

The main effects to be examined are the extent of the fracture that is possible with foam, the placement of proppant, the clean up of foam, fluid leakoff effects, effect of rock properties, and the predictability of foam fracturing treatment design.

IV. FOAM FRACTURE DESIGNS

The Devonian wells in which Foam Fracs were performed were first stimulated with approximate rates and volumes using properties assessed by the service companies for these treatments. The Kerns and Perkins calculations for the six wells shown in Table 3 are given below in Table 4.

Many other cases were run to find out what input properties were most sensitive. As it usually turns out, the Fluid Loss Coefficient is the variable having the greatest effect. From my conversations with the service companies and Amoco Oil Company, this is the area in which we know the least.

Blaurer's[2] original fluid loss data is in doubt and was taken out of context to use in low permeability situations. His lowest permeability tested was 170 md. He finds a fluid loss coefficient of 10^{-5} to 10^{-4} ft/$\sqrt{min}$. In service company tests they find 1 md cores give data in the 10^{-3} ft/$\sqrt{min}$ range. This approximate value (0.002 ft/$\sqrt{min}$) was used in the calculations for Table 4. King[22] of Amoco reports fluid loss as high as 0.1 (10^{-1} ft/$\sqrt{min}$) with 1 md cores. He admits his results are pessimistic but we know that somewhere between his data and Blaurer's data is the correct value of fluid leakoff.

Viscosity is an important variable and provides another area of uncertainty since Foam is a non-Newtonian fluid. Its viscosity is a function of shear rate which means that it is a function of injection rate, fracture width and leakoff velocity. The behavior of the viscosity of the foam is felt to be significant to the effective length of the fracture and the width to length rates of the fracture which determines allowable sand volume.

Increases in the injection rate increase the size of the fracture because more fluid is put into the fracture in a given time period. This decreases foam viscosity and increases fluid leakoff so a careful study of all effects is required.

Fracture Height is approximated by the perforated interval plus a small amount. On these small treatments frac height is fairly closely estimated. MHF and extremely large treatments can have frac height as a very important variable since it is possible to fracture out of the producing zone.

Rock Modulus variations have a lower order effect and is not noticeable in the prediction of fracture geometry.

After the first cases were evaluated, the foam rheology was examined more closely. Inputs in viscosity values from Sunder Advani, service labs and others indicated that a low effective viscosity of about 25cp was possible. Based on this information, the Kristianovich and Zhelton program was run repeating one of the earlier cases in Table 4, Well ID KY-WV2. Table 5 shows this result where the fracture length, width, and volume are all reduced because of the lower effective viscosity and higher effective fluid loss coefficient (0.0042 $ft/\sqrt{min}$).

This type of program could be further modified to account for the change in viscosity of the foam as it flows down the fracture and as it leaks into the formation and into micro-fracture. Table 5 is believed to be fairly accurate representation of the created fracture geometry. A pressure build up analysis is required to prove this, however.

A definite need exists for a more accurate modeling of the foams behavior in the fracture and as it leaks into microcracks and fissures.

TABLE 4. DEVONIAN FOAM FRAC JOBS.

Well I.D. KY-WV1
Max. Job Time (Min.) 35.
Time Increment (Min.) 5.
Injection Rate (BPM) 30.

Viscosity (CP) 500.
Frac Height (ft) 100.
Rock Modulus (psi) 5000000.

OVERALL FLUID LOSS COEF.= 0.00200

WIDTH (IN.)	LENGTH (FT.)	VOLUME (CU.FT.)	EFF. (%)	TIME (MIN.)
0.[illegible]	114.51	555.24	65.92	5.00
0.33	186.44	1021.13	60.62	10.00
0.35	246.49	1447.64	57.29	15.00
0.37	299.65	1847.91	54.85	20.00
0.38	348.15	2229.04	52.93	25.00
0.40	393.28	2595.92	51.37	30.00
0.41	435.54	2949.12	50.02	35.00

Well I. D. KY-WV2
Max. Job Time (Min.) 50.
Time Increment (Min.) 5.0
Injection Rate (BPM) 25.0

Viscosity (CP) 500.
Frac Height (ft) 100.
Rock Modulus (psi) 5000000.

OVERALL FLUID LOSS COEF.= 0.00200

WIDTH (IN.)	LENGTH (FT.)	VOLUME (CU.FT.)	EFF. (%)	TIME (MIN.)
0.27	100.33	449.70	64.07	5.00
0.30	162.72	823.05	58.63	10.00
0.33	214.59	1163.16	55.24	15.00
0.34	260.39	1481.35	52.76	20.00
0.3[illegible]	302.10	1783.62	50.82	25.00
0.3[illegible]	340.84	2074.01	49.25	30.00
0.37	377.07	2353.15	47.90	35.00
0.38	411.34	2623.44	46.72	40.00
0.39	443.96	2886.03	45.69	45.00
0.40	47[illegible].19	3141.85	44.76	50.00

TABLE 4. DEVONIAN FOAM FRAC JOBS (Cont'd).

Well I.D. ORBIT
Max. Job Time (Min.) 45.
Time Increment (Min.) 5.0
Injection Rate (BPM) 25.0

Viscosity (CP) 5000.
Frac Height (ft) 150.
Rock Modulus (PSI)

OVERALL FLUID LOSS COEF.= 0.00200

WIDTH (IN.)	LENGTH (FT.)	VOLUME (CU.FT.)	EFF. (%)	TIME (MIN.)
0.40	50.83	512.70	73.05	5.00
0.46	83.99	960.47	68.42	10.00
0.49	112.09	1377.67	65.43	15.00
0.52	137.29	1775.23	63.23	20.00
0.54	160.43	2156.86	61.46	25.00
0.56	182.05	2526.07	59.98	30.00
0.57	202.46	2884.86	58.72	35.00
0.58	221.87	3234.66	57.61	40.00
0.60	240.49	3577.54	56.63	45.00

USED 6.05 UNITS

Well I.D. Ky-WV3
Max. Job Time (Min.) 50.
Time Increment (Min.) 5.0
Injection Rate (BPM) 25.

Viscosity (CP) 500.
Frac Height (ft) 80.
Rock Modulus (PSI) 5000000.

OVERALL FLUID LOSS COEF.= 0.00200

WIDTH (IN.)	LENGTH (FT.)	VOLUME (CU.FT.)	EFF. (%)	TIME (MIN.)
0.28	121.65	457.70	65.21	5.00
0.32	197.76	840.19	59.85	10.00
0.34	261.20	1189.69	56.50	15.00
0.36	317.31	1517.28	54.04	20.00
0.37	368.46	1828.93	52.12	25.00
0.38	416.03	2128.70	50.55	30.00
0.39	460.55	2417.12	49.20	35.00
0.40	502.69	2696.61	48.03	40.00
0.41	542.81	2968.35	46.99	45.00
0.42	581.23	3233.24	46.07	50.00

TABLE 4. DEVONIAN FOAM FRAC JOBS (Cont'd).

Well I.D. OSTEGO
Max. Job Time (Min.) 45.
Time Increment (Min.) 5.
Injection Rate (BPM) 25.

Viscosity (CP) 100.
Frac Height (ft) 72.
Rock Modulus (PSI) 5000000.

OVERALL FLUID LOSS COEF.= 0.00200

WIDTH (IN.)	LENGTH (FT.)	VOLUME (CU.FT.)	EFF. (%)	TIME (MIN.)
0.20	154.48	401.65	57.22	5.00
0.23	262.82	721.58	51.40	10.00
0.24	343.22	1007.35	47.84	15.00
0.26	413.68	1272.15	45.31	20.00
0.27	477.55	1522.23	43.38	25.00
0.27	536.26	1759.66	41.78	30.00
0.28	591.08	1987.31	40.45	35.00
0.29	642.74	2206.73	39.30	40.00
0.29	691.76	2419.07	38.30	45.00

USED [illegible] UNITS

Well I.D. WV/MASON
Max. Job Time (Min.) 30.
Time Increment (Min.) 5.0
Injection Rate (BPM) 40.

Viscosity (CP) 500.
Frac Height (ft) 190.
Rock Modulus (PSI) 5000000.

OVERALL FLUID LOSS COEF.= 0.00200

WIDTH (IN.)	LENGTH (FT.)	VOLUME (CU.FT.)	EFF. (%)	TIME (MIN.)
0.29	81.11	736.57	65.59	5.00
0.32	131.96	1353.44	60.26	10.00
0.35	174.39	1917.67	56.92	15.00
0.36	211.92	2446.88	54.47	20.00
0.38	246.15	2950.57	52.55	25.00
0.39	278.00	3435.26	50.98	30.00

TABLE 5. KY-WV2 WELL NEW INPUT DATA
(K -PROGRAM)

Depth: 3300 ft.
Gross Height: 100 ft.
New Height: 86 ft.
Frac Gradient: 0.7 psi/ft.
Permeability: 1.0 md.
Porosity: 0.1 dec. fraction.
Mean Sonic Travel Time: 65 μsec/ft.
Resv. Fluid Viscosity: .02 cp.

Resv. Fluid Density: 2.0 lb/cu ft.
Resv. Fluid Compressibility: 0.003 1/psi.
Reservoir Pressure: 350 psi.
Frac Fluid Viscosity at Temp: 25 cp.
Injection Rate: 25 bpm.
Gel Concentration: 0. lb/1000 gal.
Fluid Loss Add. Conc.: 0. lb/1000 gal.

** JOB DATA *****

INJECTION RATE BBL/MIN	FRAC FLUID VISCOSITY CP	GELLING AGE[illegible] LBS/[illegible]
25.00	25.0	0.

* *

COMPUTED CONDITIONS OF [illegible]

CLOSURESTRESS AT ZERO DRAWDOWN
CLOSURE STRESS AT MAXIMUM DRAW[illegible]

DYNAMIC GEOMETRY

TIME MIN	INJECTED VOLUME BBL	INJECTED VOLUME GAL	WIDTH AT WELLBORE IN	AVERAGE WIDTH IN	LENGTH FT	TO[illegible]
10.	250.	10500.	0.128	0.100	157.	
20.	500.	21000.	0.157	0.12[illegible]	219.	
30.	750.	31500.	0.17[illegible]	0.138	285.	
40.	1000.	42000.	0.191	0.150	333.	
50.	1250.	52500.	0.204	0.160	377.	

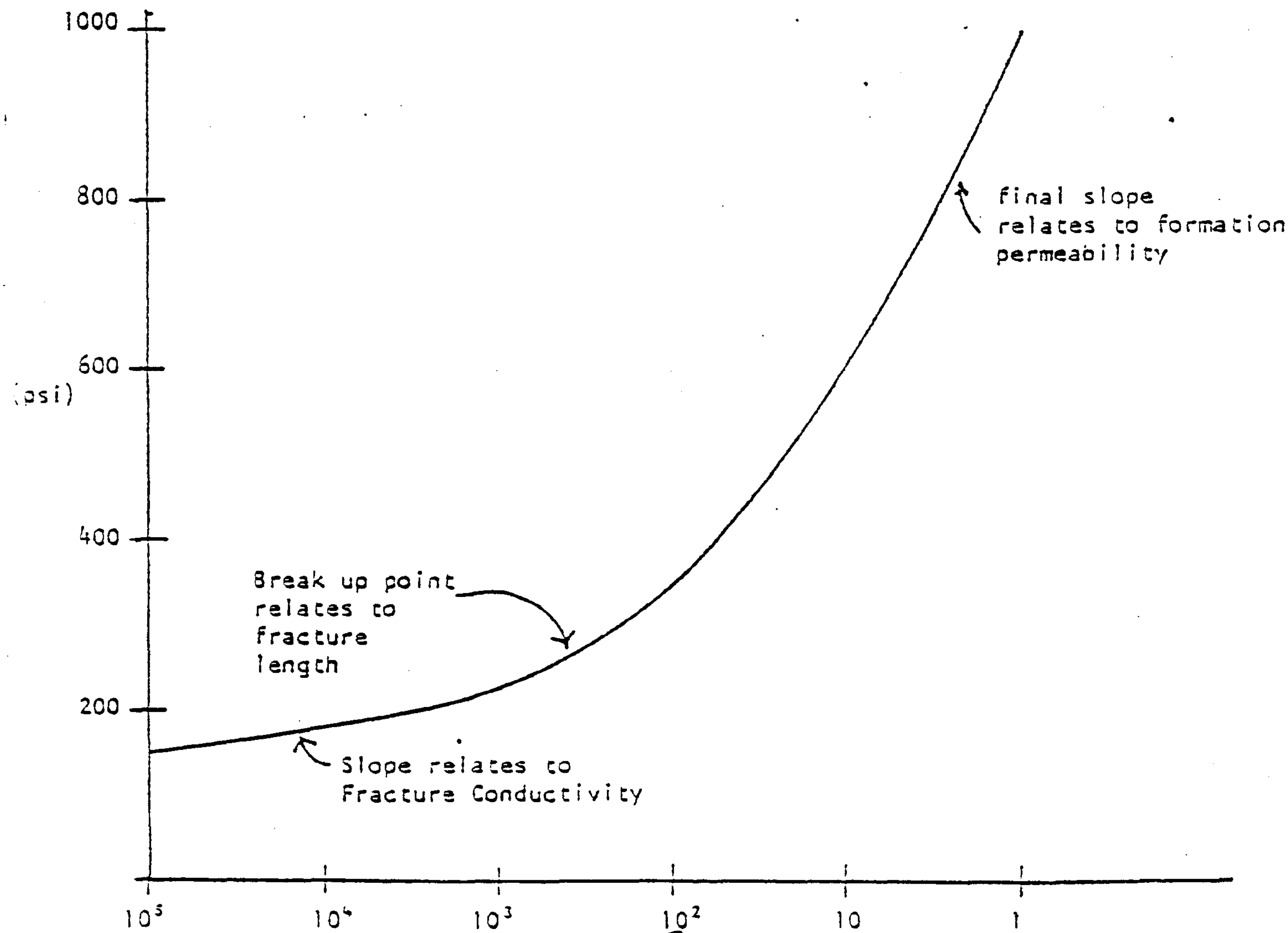
****

V. FRACTURE EVALUATION

To date the Foam Frac treatments have been judged on production increases. Unfortunately, this does not tell the entire story since the process (Foam Frac) may work perfectly, but the well is just not a producer. For this reason and to quantitatively compare wells stimulated with various techniques of all sizes, it is imperative that short term pressure buildup tests be made with bottomhole pressure bombs. The resulting data will allow a unique solution of the fracture conductivity, fracture length and effective formation permeability to be made. Such a buildup curve[13] is shown in Figure 1.

Figure 1

PRESSURE BUILDUP ANALYSIS



VI. LIMITS OF FOAM FRACTURING

Even with the good attributes of quick clean up, minimal formation impairment and low trating pressures, there are definite limits to the use of foam fluids in hydraulic fracturing treatments.

Foams are basically non-wall building fluids and are held in the fracture (kept from leaking off) by the effective viscosity of the foam. Foams are good fluids if the treating pressure and differential pressure into the formation is low and if the formation permeability is also low. King and Daneshy report in conversations that foam fluids do not have the fluid loss attributed them by Blaurer. While liquid leakoff may be low, total liquid and gas leakoff can be very high. A field example is in the Wilcox sand, a foam frac quickly sanded out from too high of fluid leakoff into a formation whose effective permeability was probably 10 md or greater. So our first limit is to only fracture low permeability reservoirs.

How is the Foam Fluid Loss Coefficient Calculated?

Foam Fluid Loss Coefficients[13] for calculations of fracture geometry. C_I is the viscosity control.

$$C_I = 0.001483 \sqrt{\frac{K \Delta p \phi}{\mu}} \qquad (1)$$

C_{II} is the compressibility of the formation control

$$C_{II} = 0.001183 \; \Delta p \sqrt{\frac{k \phi c}{\mu}} \qquad (2)$$

The total fluid loss coefficient is made up of both C_I and C_{II} as shown by Equation (3).

$$C_T = \frac{C_I \cdot C_{II}}{C_I + C_{II}}$$

where

k = permeability (md)
Δp = filtration pressure (psi)
ϕ = porosity (decimal fraction)
c = compressibility or $1/p_r$ (1/psi)
μ = effective foam viscosity (cp)

The effective foam viscosity is defined in Equation 4 below as:

$$\mu e = 9995 \left(\frac{0.228Q}{w^2H}\right)^{-0.851} \tag{4}$$

where

μ_p = plastic viscosity (cp)
Ty = yield stress (lb/ft^2)
W = dynamic frac width (in)
h = fracture height (ft)
Q = injection rate of foam (BPM)

What about foam leakoff into microfractures?

Foam leakoff will probably be very high due to the high shear rates associated with the foam leaking into a tiny crack. The best gas wells in the Devonian will probably have these microcracks or natural fractures so the use of 100 mesh sand is highly recommended to help control leakoff of the foam. It will not stop leakoff but it can slow it down and still will not damage the well's productivity. More work and testing is required in this area.

Why use Foam at shallow depths?

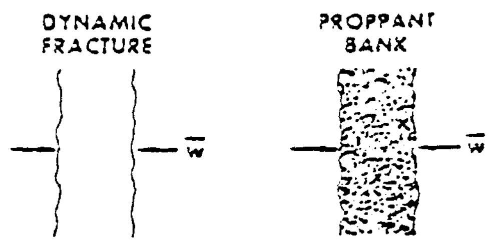
Amoco recommends the use of foam fluids only to 4000 or 5000 ft. because of economic reasons but also because formation temperatures are lower and do not cause problems. Also, the differential treating pressure into the reservoir is limited to a certain extent at these depths - remember the fluid leakoff rate of foams is sensitive to this differential pressure.

Why limit foam use to low temperatures?

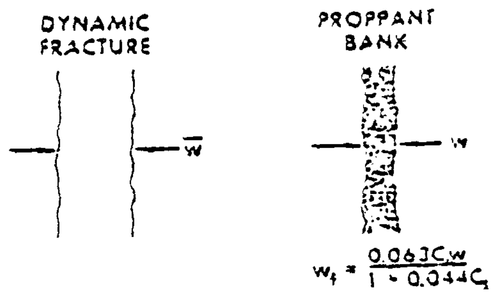
Up to 150°F no bad effects have been found on foams. Possible chemical reactions and surfactant adsorption is thought possible above 150°F. This could be overcome by redesign but is only another complication that is not desirable.

How does the amount of proppant in a foam treatment limit its results?

Foams can only carry low sand concentrations using the conventional blender addition of sand since the water phase is only about 1/4 of the total foam fluid volume. Sand concentrations shown in Table 3 average only about 1 lb. of sand per gallon of foam. Foam does not allow the sand to settle, hence the dynamic width closes on the sand to make a very narrow fracture channel. This effect is illustrated in Figure 2.



a. Sandbank width is equal to dynamic width when proppant settles to the bottom of the fracture.



b. Sandbank width will be 25% to 50% of dynamic width when proppant is suspended in the frac fluid.

Fig. 2 Sandbank width.

Our standard fracture programs calculate an average dynamic fracture width ($\overline{w}$). This is about the final width (w_f) in frac jobs that use thin fluids which allow sand to settle. This effect is described by Equation 5 below.

$$w_f = \frac{0.063\ (C_s)\ \overline{w}}{1.0 + 0.044(C_s)} \tag{5}$$

where

w_f = final fracture width (in)
C_s = sand concentration (lb/gal of foam fluid)
$\overline{w}$ = average dynamic fracture width (in).

As an example, let us assume that 1 lb of sand is used (average) for each gallon of foam fracturing fluid. Then by solving Equation 5 assuming $\overline{w}$ = 1, we see that the final fracture width (w_f) is only 0.06 or 6 percent of the original average width. Unless very large, permeable sand is used or unless formation permeability is extremely low, the overall stimulation result will be reduced. This graphically illustrates a major limit of foam fracturing at present. Also, we can see that any fracturing technique in which sand settling is prevented while not using high concentrations of sand will have narrower widths than would normally be calculated.

What about the rheology of foams?

Foams are very non-Newtonian type fluds. They shear thin or decrease in viscosity with high shear rates. Blaurer[2] and others have chosen to use a Bingham fluid model to represent the effective viscosity in the fracture. Blaurer's equation is shown in Equation 6.

$$\mu_e = \mu_p + 7.162\ \frac{T_y\ w^2\ h}{Q} \tag{6}$$

where

μ_p = plastic viscosity (5.4 cp at 75% Quality)

T_y = yield strength (44 $lb_f/100\ ft^2$ at 75% Quality)

w = frac width (in)

h = frac height (ft)

Q = injection rate (BPM)

By using this data and replotting, a power law model is derived to calculate the effective foam fracture viscosity. These expressions are given in Equations 7, 8 and 9.

$$\tau = K\dot{\gamma}^n \qquad (7)$$

where

K = 19.56

n = 0.149

τ = shear stress

since $$\dot{\gamma} = \frac{0.2228\,Q}{w^2 h} \text{ in the fracture} \qquad (8)$$

then $$\mu_e = 9995\ (\dot{\gamma}^{-0.351}) \qquad (9)$$

for effective foam viscosity in the fracture.

While Equation 9 shows foam viscosity values of several hundred centipoise in the planar fracture, leakoff into micro-cracks and fissures can reduce this viscosity to 10 cp. or less. This reduction in viscosity is caused by the extremely high rates of shear governed by the very narrow crack widths.

VII. MODIFIED TREATMENTS

In a short discussion we will try and decide how to retain the desirable parts of the foam fracs but design around the limits of the foam fluids.

One limit mentioned earlier was that the suspension of sand by the foam was too good - very little settled. A wider fracture and higher sand concentrations are desirable.

We have several ways to do this. One method is to make a weaker foam; however, instead of changing foam properties we may want to inject slugs of water carrying higher sand concentrations in alternating sequences with the foam fluids. Another choice is to make a sub foam or aerated water fluid to retain quick clean up but to carry more sand. Sub foams may cost less as well. Another approach is to use larger grain sands since the formation can only close down to one grain diameter with the low closure stresses encountered at these depths.

Efforts are underway by Fracmaster and Nowsco to build a proppant injector to inject high concentrations of sand directly into the foam. This would have the effect of keeping the final fracture width close to the dynamic fracture width.

In areas where fluid leakoff seems to be a problem, the use of polymers or fluid loss additives may help complete the stimulation treatments (recommended by King[22]). Polymers or additions may make the foams more stable; too stable for the way in which they are presently used. Lab tests to redesign foams may be necessary and foam breaking by encapsulated defoamers may be required. Field procedures could also be changed to flow back the wells at lower rates if there is a problem of the foam carrying sand back out of the fracture after treatment.

Much work on foams is underway, but it is not yet completed. When information on accurate fluid leakoff measurements and friction loss testing is made public, it is hoped that we use it to improve our foam designs and to employ foam fluids for broader applications.

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JOB DATA

INJECTION RATE BBL/MIN	FRAC FLUID VISCOSITY CP	GELLING AGENT LBS/1000 GAL	FLUID LOSS ADDITIVE LBS/1000 GAL
25.00	25.0	0.	0.

COMPUTED CONDITIONS OF DYNAMIC FRACTURE

CLOSURESTRESS AT ZERO DRAWDOWN = 1960. PSI
CLOSURE STRESS AT MAXIMUM DRAWDOWN = 2310. PSI

		DYNAMIC GEOMETRY				FLUID LOSS		
INJECTED VOLUME BBL	INJECTED VOLUME GAL	WIDTH AT WELLBORE IN	AVERAGE WIDTH IN	LENGTH FT	TOTAL VOLUME CU FT	FILTRATION PRESSURE PSI	FLUID LOSS COEFF-CVC FT/SQRT(MIN)	FLUID EFFICIENCY PER CENT
250.	10500.	0.128	0.100	157.	263.	2122.	0.0042	18.7
500.	21000.	0.157	0.123	229.	469.	2094.	0.0042	16.7
750.	31500.	0.176	0.138	285.	657.	2080.	0.0042	15.4
1000.	42000.	0.191	0.150	333.	832.	2072.	0.0042	14.8
1250.	52500.	0.204	0.160	375.	1000.	2065.	0.0042	14.2